ACCESSION #: 9308310239
LICENSEE EVENT REPORT (LER)

FACILITY NAME: Palo Verde Unit 2 PAGE: 1 OF 16

DOCKET NUMBER: 05000529

TITLE: Manual Reactor Trip Following a Steam Generator Tube Rupture
EVENT DATE: 03/14/93 LER #: 93-001-02 REPORT DATE: 08/14/93

OTHER FACILITIES INVOLVED: N/A DOCKET NO: 05000

OPERATING MODE: 1 POWER LEVEL: 098

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION:
50.73(a)(2)(i), 50.73(a)(2)(ii), 50.73(a)(2)(iv), OTHER - Special Report

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COMPONENT FAILURE DESCRIPTION:
CAUSE: SYSTEM: COMPONENT: MANUFACTURER:
REPORTABLE NPRDS:

SUPPLEMENTAL REPORT EXPECTED: NO

ABSTRACT:

On March 14, 1993, at approximately 0434 MST, Palo Verde Unit 2 was in Mode 1 (POWER OPERATION), operating at approximately 98 percent power when a steam generator tube ruptured in Steam Generator 2. At approximately 0447 MST, the reactor was manually tripped due to low pressurizer level and pressure. Approximately 22 seconds later, valid actuations of the Safety Injection Actuation System (SIAS) and the Containment Isolation Actuation System (CIAS) occurred due to low pressurizer pressure. Pressurizer level was restored and a controlled cooldown and depressurization of the Reactor Coolant System (RCS) was conducted in accordance with approved procedures. A steam generator tube rupture in Steam Generator 2 was diagnosed, and the steam generator was successfully isolated.

This event was investigated in accordance with the PVNGS Incident Investigation Program. The rupture of the steam generator tube was due

to intergranular attack/intergranular stress corrosion cracking (IGA/IGSCC) which occurred as a result of tube-to-tube crevice formation. The cause of the SIAS and CIAS was the loss of RCS inventory and the contraction of the RCS upon reactor trip. Pursuant to Technical Specifications 3.5.2, ACTION b, this LER also provides the Special Report required for an Emergency Core Cooling System actuation.

There have been no previous similar events reported pursuant to 10CFR50.73.

END OF ABSTRACT

I. DESCRIPTION OF WHAT OCCURRED:

A. Initial Conditions:

At 0434 MST on March 14, 1993, Palo Verde Unit 2 was in Mode 1 (POWER OPERATION) at approximately 98 percent power.

B. Reportable Event Description (Including Dates and Approximate Times of Major Occurrences):

Event Classification: The completion of any nuclear plant shutdown required by Technical Specifications;

an event or condition that resulted in a principal safety barrier being seriously degraded; and

an event that resulted in an automatic actuation of an Engineered Safety Feature (ESF) (JE) and the Reactor Protection System (RPS)(JE).

At approximately 0434 MST on March 14, 1993, Palo Verde Unit 2 experienced a steam generator tube rupture in Steam Generator 2 (AB). At approximately 0447 MST, the reactor (AC) was manually tripped due to low pressurizer (AB) level and pressure. Approximately 22 seconds later, valid Engineered Safety Feature Actuation System (ESFAS) actuations of the Safety Injection Actuation System (SIAS) (JI)(BP) and the Containment Isolation Actuation System (CIAS) (JI) (BD) occurred due to low pressurizer pressure. Pressurizer level was restored and a controlled cooldown and depressurization of the Reactor Coolant System (RCS) (AB) was conducted in accordance with approved procedures. A steam generator tube rupture in Steam Generator 2 was diagnosed, and the steam generator was successfully isolated.

Prior to the, event, in July, 1992, Unit 2 began measuring detectable levels of tritium at a level of 1.0 E-5 microCurie/gram (mu Ci/gm) in the secondary system. No other nuclides typically present in primary-to-secondary leakage, such as iodine and xenon, were detected. The initial leak rate was determined to be approximately 1 gallon per day (gpd). A Chemistry Action Document (CAD) was initiated to monitor the Steam Generator 1 Blowdown Radiation Monitor (RU-4) (IL)(MON), Steam Generator 2 Blowdown Radiation Monitor (RU-5) (IL)(MON), and the Condenser Vacuum Exhaust Radiation Monitor (RU-141) (IL)(MON) every 4 hours to

trend potential increases in activity. Trend information was logged in the Unit 2 Radiation Monitoring System (RMS)/Effluent Shift Log. On February 3, 1993, RU-5 indicated activity above background in the Steam Generator 2 (AB)(SG) blowdown line. On February 4, 1993, RU-4 and RU-5 setpoints were lowered, in accordance with procedures, to more closely monitor potential increases in leakage. On February 20, 1993, Iodine-131 was detected in Steam Generator 2 blowdown at a concentration of approximately 3.0 E-8 mu Ci/gm. Iodine-131 activity trends increased from 3.0 E-8 mu Ci/gm to 1.0 E-7 mu Ci/gm between February 20 and February 27, 1993. RU-4 and RU-5 also exhibited trend increases. On February 28, 1993, a CAD was issued to increase the monitoring of RU-4, RU-5, and RU-141 to every 2 hours. RU-4 and RU-5 setpoints were periodically adjusted in accordance with procedures, to closely monitor increases and decreases in activity levels. On March 3, 1993, Chemistry personnel (utility nonlicensed) began using Iodine-131 activity levels to calculate the steam generator leak rate. Initial Iodine-131 leak rate calculations indicated a leak of approximately 8 gpd. From March 9 to March 13, 1993, the leak rate calculation indicated a steady leak of approximately 10 gpd. [NOTE: Post event calculations using tritium leak rate data indicate that the actual leak rate during this time period was approximately 20 gpd.]

On the morning of March 14, 1993, at approximately 0025 MST, the Gas Stripper (CA)(DGS) was placed in service to de-gas the Reactor Coolant System (RCS) (AB) in preparation for the upcoming refueling outage. Placing the Gas Stripper into service caused an anticipated boration of the RCS, resulting in a slight drop (approximately 0.75 degree Fahrenheit) in RCS average temperature (Tave). Control Room (NA) personnel (utility-licensed) responded to the slow temperature decrease by diluting the Volume Control Tank (VCT) (CA)(TK) and placing the deborating ion exchanger into service. The decrease in RCS Tave caused pressurizer level to drop approximately 0.5 percent over a three-hour period.

At approximately 0434 MST, Control Room personnel observed a notable decrease in pressurizer (AB)(PZR) level and pressure. Control Room personnel suspected that a leak in the Gas Stripper was causing the decrease in pressurizer level. The Gas Stripper, which is not normally in operation, had been recently placed in service to support the upcoming Unit 2 refueling outage. Concurrently, an alarm (IB)(ALM) was received on the Steam Generator 2 Main Steam Line Radiation Monitor (RU-140) (IL)(MON), Channel A. The RU-140 alarm was acknowledged and announced in the Control Room.

At approximately 0436 MST, Control Room personnel started a third charging pump (CB)(P) and energized the pressurizer back-up heaters (AB)(EHTR) in order to recover pressurizer level and pressure. At this time, the Nuclear Cooling Water Radiation Monitor (RU-6) (IL)(MON) alarmed and cleared. Control Room personnel performed a check of the Containment Building (NH) parameters (i.e., pressure, sump levels, temperature, and humidity) to determine if there was a leak inside Containment. Control Room personnel suspected there may have been a slight increase in Containment Building pressure but were unable to confirm their suspicion.

At approximately 0438 MST, an alarm was received on the Auxiliary Steam Condensate Receiver Tank Radiation Monitor (RU-7) (IL)(MON). The alarm was acknowledged and announced in the Control Room. This alarm supported operator suspicion of a Gas Stripper leak.

At approximately 0440 MST, Control Room personnel isolated letdown flow. The Control Room Supervisor (CRS) (utility-licensed) suggested a manual reactor (AB)(RCT) trip, but the Shift Supervisor (SS) (utility-licensed) felt the isolation of letdown might have slowed the rate of decrease in the pressurizer level and elected to wait to see if the level would recover. Control Room personnel displayed a histogram of radiation monitors which are associated with a steam generator tube rupture (SGTR) on the RMS (IL). The RMS showed that only RU-140 and RU-7 were in alarm. The Unit 2 RMS technician (utility-nonlicensed) was notified by a Control Room operator of the alarms on RU-140, Channels A and B. The RMS technician notified Radiation Protection personnel (utility and contractor-nonlicensed) and proceeded to the effluent office to check trends on RU-4, RU-5 and RU-140.

During this period, pressurizer level and RCS pressure continued to decrease. To preclude the possibility of a radiation release into the atmosphere, Control Room personnel removed Steam Bypass Control System (SBCS) Valves 1007 (JI)(V) and 1008 (JI)(V) from service and disabled the condensate draw-off controller (KA)(LCV). These actions were taken because SBCS Valves 1007 and 1008 relieve directly into the atmosphere and the draw-off could result in contamination of the Condensate Storage Tank (KA)(TK). Concurrent to removing the 2 SBCS valves from service, SBCS Valve 1003 (JI)(V) was returned to service to compensate, in part, for removal of the valves that relieve to the atmosphere. At approximately 0441 MST, RU-140, Channel B alarmed again, and went in and out of high alarm repeatedly. The CRS conducted a briefing with Control Room personnel and discussed actions to be taken in the event of a steam generator tube leak.

At approximately 0447 MST, the pressurizer heaters de-energized due to a pressurizer low level of 26 percent, and the SS directed a manual trip of the reactor. The main turbine (TA)(TRB) tripped as a result of the manual reactor trip. Primary system pressure decreased below the low pressurizer pressure Engineered Safety Feature Actuation System (ESFAS) (JE) setpoint of 1837 pounds per square inch absolute (psia) due to the loss of RCS inventory and the contraction of the RCS due to a decrease in RCS temperature upon reactor trip. Valid actuations of the Safety Injection Actuation System (SIAS) (JE) and Containment Isolation Actuation System (CIAS) (JE) were received 22 seconds after the reactor trip due to low pressurizer pressure. Pressurizer level indicated below zero percent level and pressurizer pressure decreased to 1677 psia.

High Pressure Safety Injection (HPSI) (P)(BQ) restored pressurizer level to approximately 4 percent and pressurizer pressure to approximately 1880 psia. Control Room personnel stopped Reactor Coolant Pumps (RCP) 1B and 2B (AB)(P). RCP 1B pressurizer spray valve (AB)(V) was out-of-service so this combination of RCPs was selected to maintain pressurizer spray capability.

The RMS technician monitored activities until Control Room personnel manually tripped the reactor. The RMS technician informed the Chemistry technician of the alarms received on RU-140. The RMS technician was concerned with a potential steam release and requested that the Chemistry technician obtain main steam samples for analysis. The RU-140 alarms cleared shortly after the reactor trip.

All safety systems functioned as required. Following the SIAS, the combined makeup from the HPSI and charging pumps slowly increased pressurizer level. Pressurizer pressure was maintained at approximately 1872 psia until a plant cooldown and depressurization was initiated.

The Palo Verde Nuclear Generating Station (PVNGS) Emergency Plan Implementing Procedure, "Emergency Classification," (EPIP-02) required the declaration of a Notification of Unusual Event (NUE) for an event resulting in a SIAS actuation caused by a valid low pressurizer pressure condition. At approximately 0458 MST, the SS declared an NUE due to the valid SIAS actuation. At approximately 0502 MST, the emergency classification was upgraded to an Alert, due to RCS leakage in excess of 44 gallons per minute (gpm). At the time the emergency classification was determined, Control Room HPSI flow indication was zero, letdown flow was isolated, 3 charging pumps were in operation, and pressurizer level appeared to be increasing slowly. This indicated to the SS that the leak was within the capacity of the 3 charging pumps.

Post-event calculations indicated that actual RCS leak rate was approximately 240 gpm, which is in excess of charging pump capacity, for a period of approximately seven minutes immediately prior to the reactor trip. When plant parameters were reviewed following the reactor trip, pressurizer level had been restored and was increasing with three charging pumps running and no indication of HPSI flow. Under the conditions observed after the trip, the RCS leak rate was not perceived to be in excess of charging pump capacity and the RCS inventory loss was under control.

The CRS, using the Emergency Operations Procedure Diagnostic Logic Tree (DLT), diagnosed a reactor trip because plant conditions did not allow the diagnosis for a specific optimum recovery procedure. However, the entry conditions for the reactor trip recovery procedure could not be met because pressurizer level was not greater than 10 percent. The SS directed the CRS to re-diagnose the event but, as before, the diagnosis was that of a reactor trip and entry conditions were still not satisfied. At approximately 0502 MST, the CRS entered the Functional Recovery Procedure (FRP) due to inconclusive diagnosis using the DLT.

Although Control Room personnel suspected a SGTR, the diagnosis was not made immediately because the DLT used a "snap-shot" philosophy (i.e., what is occurring at the specific time of observation). This philosophy does not direct the operator to consider previous trends or alarms. Also, the RMS response to the event was confusing to Control Room personnel and it was not clear why the RU-140 alarms were received. The RU-140 alarms did not act in a manner consistent with the simulator display during training exercises. In simulator scenarios, RU-140 does not alarm until late in the event and the alarms remain throughout the event. It was further confusing to Control Room personnel that the primary indicator alarms for a SGTR (RU-4, RU-5, and RU-141) were not present. Radiation Monitors RU-4 and RU-5 had low flow indications because they were isolated upon the SIAS actuation. These three alarms are used as indicators of a SGTR event.

The FRP directed Control Room personnel to align charging pump suction directly to the Refueling Water Tank (BP)(TK) and close the VCT outlet. After Control Room personnel performed this function the "E" charging pump (CB)(P) tripped on low suction pressure. The operators aligned charging for an alternate boration flow path per the FRP, and restarted charging pump "E".

At approximately 0520 MST, Control Room personnel restored RU-4 and RU-5, which had been isolated by the SIAS, as directed by the FRP. At approximately 0529 MST, RU-5 reached the alert and high alarm setpoints, and at approximately 0531 MST, RU-141 reached its alert setpoint. Control Room personnel then had positive confirmation of a SGTR in Steam Generator 2.

Following the reactor trip, the crew had shifted the condenser post-filter blower (SH)(BLO) into the through-filter mode per the Steam Generator Tube Leak Abnormal Operating Procedure. The crew later reported that they felt the event was being mitigated because the release was minimized by the condenser exhaust filter (SH)(FLT).

The Nuclear Regulatory Commission Operations Center was notified of the event at approximately 0530 MST. The Emergency Response Data System (IB) was activated by Control Room personnel at approximately 0614 MST.

The CRS continued through the FRP, directing the crew to realign various systems into normal shutdown lineups. It was the CRS's intention to proceed through the FRP until RCS depressurization was directed and then once depressurized, use HPSI injection to restore pressurizer level. Once pressurizer level was restored to above 33 percent, the Pressure and Inventory Control Safety Function success criteria would allow the FRP to be exited and a re-diagnosis into the SGTR Procedure to be completed. This strategy would succeed in isolating the SGTR, but it is different than the SGTR strategy that is designed into the FRP. In the FRP, it is assumed that the CRS finds indications of an SGTR at Step 3.21, and then performs the steps in an attachment which are similar to the isolation and depressurization steps in the recovery procedure for a SGTR.

Control Room personnel continued recovery actions per the FRP to restore pressurizer level to greater than 33 percent. At approximately 0604 MST, the CRS directed an RCS cooldown to 545 degrees Fahrenheit and a depressurization to 1500 psia. HPSI injection increased as the RCS depressurized. Pressurizer level was restored to 33 percent and Control Room personnel stabilized RCS pressure and temperature. The acceptance criteria for the Pressure and Inventory Control Safety Function success path were met and at approximately 0624 MST, the CRS exited the FRP, again performed the DLT, and diagnosed an SGTR. The SGTR Recovery Procedure was entered at approximately 0645 MST. The SS then directed that crew turnover commence. At approximately 0721 MST, the RCS cooldown was restarted per the SGTR procedure, and at approximately 0728 MST, Steam Generator 2 was isolated.

The Pressurized Thermal Shock limit of 200 degrees Fahrenheit subcooled margin was approached during RCS depressurization and

cooldown. Isolated Steam Generator 2 pressure remained fairly constant and the RCS pressure was being maintained above the isolated steam generator pressure. steam Generator 2 was cooled down by allowing Steam Generator 2 pressure to exceed RCS pressure, thus back-flowing from the steam generator into the RCS. This allowed the ruptured steam generator to be cooled by a series of auxiliary feedwater additions. Chemistry samples were taken to ensure that RCS boron and chemistry limits would not be exceeded during this evolution.

At approximately 1029 MST, on March 14, 1993, Unit 2 entered Mode 4 (HOT SHUTDOWN). At approximately 1137 MST, following verification of proper safety system actuation, the SIAS and CIAS signals were reset. At approximately 1637 MST, the SGTR Recovery Procedure was exited.

At approximately 2235 MST, Shutdown Cooling (BP) Train A was placed in service.

At approximately 0556 MST, on March 15, 1993, Unit 2 entered Mode 5 (COLD SHUTDOWN).

The requirement of Technical Specification 3.4.5.2, Action b, for a primary-to-secondary leak which is greater than 720 gpd through any one steam generator was met (i.e., reduce the leakage rate to within limits within 4 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours).

The Alert was terminated at approximately 0115 MST, on March 15, 1993.

Unit 2 is currently in a scheduled refueling outage.

C. Status of structures, systems, or components that were inoperable at the start of the event that contributed to the event:

In addition to the SGTR described in Section I.B., RU-141 had an undetected equipment failure that caused it to read approximately 6 times less than grab sample activity. The monitor would have reached the alert alarm setpoint during the event at approximately 0456 MST, on March 14, 1993, if it had been indicating properly.

D. Cause of each component or system failure, if known:

A Steam Generator Tube Rupture Task Force of specialized APS personnel as well as industry consultants was formed to perform an equipment root cause of failure analysis. The task force

assembled a flow chart of possible failure modes to develop action plans for eddy current testing, tube pull selection, engineering analysis, and laboratory techniques. Using the information obtained from these activities, the task force concluded that the rupture of the steam generator tube was due to intergranular attack/intergranular stress corrosion cracking (IGA/IGSCC) which occurred as a result of tube-to-tube crevice formation. Several additional contributing factors such as increased sulfate levels due to resin intrusion, likelihood of cold working due to surface scratches, a less than standard microstructure in the ruptured tube, and increased susceptibility of contaminant concentration in the upper region of the tube bundle were also identified by the task force. The Steam Generator Tube Rupture Analysis Report was submitted by letter 102-02569, dated July 18, 1993, from W. F. Conway to the NRC. This report includes the event description and safety assessment, the steam generator design, operating history, analytical studies, and inspection, tube examination results, root cause of failure, Regulatory Guide 1.121 evaluation, recovery plan and corrective actions, and the basis for the restart of Unit 2 following the scheduled refueling outage. In response to a request by the NRC, additional information concerning the above Steam Generator Tube Rupture Analysis Report was submitted by letter 102-02593, dated July 30, 1993, from W. F. Conway to the NRC.

An equipment root cause of failure analysis (ERCFA) was performed for RU-141 under the PVNGS Incident Investigation Program. RU-141 has been subject to operability problems associated with moisture in the condenser air removal system

(CARS). The effluent stream from the CARS is a high humidity air stream which during sampling condenses in the particulate filter and gas detector of RU-141. Previous commitments have been made to the NRC to resolve the moisture problem affecting the operability of RU-141. As a result, heat tracing and other temporary modifications were installed to improve operability. During the ERCFA, moisture was not found when the detector was removed from the sample chamber. The scintillation crystal was removed and found to be deteriorated (i.e., distorted and yellowed). In addition, the photo multiplier tube was found to have aged. The ERCFA determined that the reduced sensitivity of RU-141 was caused by the tube aging and the crystal deterioration which had resulted from elevated temperature conditions from the heat tracing. Although the heat tracing was within manufacturer's limits, the elevated temperatures caused the aging and deterioration. The reduction in sensitivity caused RU-141 to under-respond by a factor of 6 times the grab sample activity.

E. Failure mode, mechanism, and effect of each failed component, if known:

As discussed in the correspondence to the NRC, the failure mechanism leading to the steam generator tube rupture was due to IGA/IGSCC which occurred as a result of tube-to-tube crevice formation. The crevice, together with the consequential heat flux, led to an aggressive environment under a tenacious ridge deposit. As a consequence, a long deep crack, initiating under the ridge deposit, led to the loss of structural integrity under normal operating conditions.

The failure mode, mechanism, and effect of RU-141 are discussed in the previous section.

F. For failures of components with multiple functions, list of systems or secondary functions that were also affected:

Not applicable - no secondary functions were affected as a result of the component failures. Since activity calculations for effluent release permits are based on monitor to grab sample ratios rather than specific readings, and RU-141 trends indicated increasing activity, the factor of 6 difference does not affect effluent release permit calculations. Therefore, there are no effects on effluent release permit calculations associated with releases via the condenser exhaust. Additionally, there was no adverse effect on the High Range Condenser Exhaust Radiation Monitor (RU-142) (IL)(MON). Although the 2 monitors work in parallel to provide 11 decades of monitoring and indication, there is a decade overlap such that RU-142 would have alarmed as required.

G. For a failure that rendered a train of a safety system inoperable, estimated time elapsed from the discovery of the failure until the train was returned to service:

Not applicable - no failures that rendered a train of a safety system inoperable were involved.

H. Method of discovery of each component or system failure or procedural error:

The SGTR was discovered as described in Section I.B.

During the event, it was discovered that RU-141 was not reading correctly. A comparison of the monitor readings with the grab sample results obtained during the event indicated that the monitor was reading approximately 6 times less than the actual

gaseous activity. As a result, the initial offsite dose projections based on the release rate indicated by RU-141 underestimated calculated doses by a factor of 6. As soon as the discrepancy was discovered, subsequent offsite dose projections were corrected by increasing the monitor readings by a factor of 6 to compensate for the under-response. As a result of the discrepancy, an ERCFA for RU-141 was initiated.

During the investigation of this event, it was determined that the PVNGS DLT and FRP differ from the Combustion Engineering "Emergency Procedure Guidelines," (CEN-152). CEN-152 uses activity trends on the secondary side to aid in diagnosis of events. The PVNGS DLT differs in that alarm indications rather than activity trends are used. Additionally, there is a continuously applicable step in the Containment Integrity Safety Function section of CEN-152 to check for indications of secondary side activity, and if indicated, steps to depressurize and isolate the affected steam generator are performed. The PVNGS FRP only checks once for secondary side activity. These deviations are not justified in the Plant

Specific Technical Guidelines. A SGTR may have been diagnosed earlier in this event if there had been a step in the DLT to trend secondary side activity or in the FRP to continuously check for indications of secondary side activity.

I. Cause of Event:

An investigation of this event was conducted in accordance with the PVNGS Incident Investigation Program. The manual reactor trip was initiated due to low pressurizer level and pressure. Approximately 22 seconds later, valid actuations of the Safety Injection Actuation System (SIAS) and the Containment Isolation Actuation System (CIAS) occurred due to low pressurizer pressure. The cause of the RU-141 failure is discussed in Section I.D. The cause of the RCS leakage was a SGTR in Steam Generator 2.

A Steam Generator Tube Rupture Task Force was formed to perform an equipment root cause of failure analysis. The task force identified the most probable causal factors for degradation of the affected tubes. The evidence indicated that the rupture of the steam generator tube was due to IGA/IGSCC which occurred as a result of tube-to-tube crevice formation (SALP Cause Code C: External Cause). Several additional contributing factors such as increased sulfate levels due to resin intrusion, likelihood of cold working due to surface scratches, a less than standard microstructure in-the ruptured tube, and increased susceptibility of contaminant concentration in the upper region of the tube bundle were also identified by the task force. The Steam Generator Tube Rupture Analysis Report was submitted by letter

102-02569, dated July 18, 1993, from W. F. Conway to the NRC. Additional information related to the tube failure is discussed in Sections I.D and I.E.

J. Safety System Response:

The following safety systems actuated as a result of the event:

- High Pressure Safety Injection System (BQ) , Trains A and B
- Low Pressure Safety Injection System (BP), Trains A and B
- Containment Spray System (BE), Trains A and B,
- Emergency Diesel Generators (EK), Trains A and B,

- Essential Chilled Water System (KM), Trains A and B
- Essential Cooling Water System (BI), Trains A and B,
- Essential Spray Pond System (BS), Trains A and B
- Condensate Transfer System (KA), Trains A and B,
- Control Room Essential Heating, Ventilation, and Air Conditioning (HVAC) System (AHU)(VI), Trains A and B,
- Auxiliary Building Essential HVAC System (AHU)(VF), Trains A and B,
- Fuel Building Essential HVAC System (AHU)(VG), Trains A and B,
- Engineered Safety Features Switchgear Essential HVAC System (AHU)(VJ), Trains A and B,
- Containment Isolation System (JM), and
- Auxiliary Feedwater Pump (P) (BA), Train B

K. Failed Component Information:

The cause of the RCS leakage was a tube failure in Steam Generator 2. The steam generator is a Combustion Engineering System-80 vertical U-tube heat exchanger which operates with the reactor coolant on the tube side and secondary coolant on the shell side.

RU-141 had an undetected equipment failure that caused it to read approximately 6 times less than grab sample activity. The monitor would have reached the alert alarm level setpoint during the event at approximately 0456 MST, on March 14, 1993, if it had been indicating properly. The gas monitor is a Kaman Beta Scintillator, model number KMG-HRN 450809-002, with a range of 1.0 E-6 to 1.0 E-1 mu Ci/cc.

II. ASSESSMENT OF THE SAFETY CONSEQUENCES AND IMPLICATIONS OF THIS EVENT:

A safety limit evaluation was performed as part of the PVNGS Incident Investigation. The evaluation determined that the plant responded as

designed, that no safety limits were exceeded, and that the event was bounded by current safety analyses.

Nuclear Fuel Management personnel performed a safety assessment of the event and determined that the equipment and systems assumed in the Updated Final Safety Analysis Report (UFSAR) Chapter 15 were functional and performed as required. Scenarios defined in UFSAR Chapter 6 concerning loss of coolant accidents were not challenged during this event.

The safety assessment concluded that the event did not result in a transient more severe than those previously analyzed. This determination was based on an evaluation of actual event parameters and dose assessments, compared to those contained in UFSAR, Section 15.6.3.1, Combustion Engineering Standard Safety Analysis Report, Section 15.6.3.2, and the SGTR with Loss of Offsite Power (SGTRLOP) reanalysis which was performed in accordance with Revision 1 to the "Steam Generator Tube Rupture Analysis Concerns and Justification for Continued Operation" (JCO 91-02-01). There were no adverse safety consequences or implications as a result of this event. This event did not adversely affect the safe operation of the plant or the health and safety of the public. The 2-hour exclusion area boundary thyroid dose was calculated to be less than 0.3 millirem and the 8-hour low population zone thyroid dose was calculated to be less than 0.04 millirem. These doses are much less than the Standard Review Plan 15.6.3 acceptance criteria of 30 Rem thyroid.

During the safety assessment of this event, concerns were raised regarding the differences in the timing of operator actions to isolate the ruptured steam generator as assumed in UFSAR Chapter 15 SGTR event, and the timing of those actions in the actual event. Similar concerns, however, were previously identified in October, 1991, as documented in JCO 91-02-01. In response to these concerns, the primary system equilibrium dose equivalent Iodine-131 (DEQI131) is currently limited to 0.6 mu Ci/gm in all three units, and a SGTRLOP reanalysis has been performed to verify that a more conservative treatment of operator timing, combined with the Technical Specification activity limits (1.0 and 0.1 mu Ci/gm for primary and secondary activity respectively), would not result in dose consequences greater than the acceptance criteria. The reanalysis is the most current analysis for a SGTR or SGTRLOP event. The results of the reanalysis are within the Standard Review Plan 15.6.3 acceptance criteria of 30 Rem thyroid.

The safety assessment of the event concluded that the longer interval required for isolation of the ruptured steam generator was compensated for by the low primary and secondary activities in effect at the time of the rupture. However, a supplemental evaluation was performed using a "best-estimate" transient evaluation code to evaluate the dose consequences associated with a steaming interval consistent with the actual event, with the affected generator steaming directly to the atmosphere and not through the condenser, and with DEQI131 activity levels at the Technical Specification limits. The resulting dose consequences for this supplemental case were also well within the acceptance criteria of 30 Rem thyroid and are bounded by the SGTRLOP reanalysis.

III. CORRECTIVE ACTION:

A. Immediate:

An investigation team was formed and an investigation was initiated in accordance with the PVNGS Incident Investigation Program. As part of the investigation, PVNGS initiated a root cause investigation.

B. Action to Prevent Recurrence:

As a result of the investigation, PVNGS has implemented changes to the Emergency Operating Procedures as corrective actions to address the CEN-152 DLT deviation described in Section II.H. These changes allow the CRS to consider past and present RMS alarms when performing the DLT and establishing procedure entry conditions. These changes will also allow the use of the Nitrogen-16 gamma response of the Main Steam Line Radiation Monitors (RU-140) and the use of the Steam Generator Blowdown Monitors (RU-4 and RU-5), both of which may clear by the time the CRS makes a diagnosis of the event. Changes have been made to the Emergency Operating Procedures to trend radiation monitors to aid in diagnosis of reactor trip events.

Additionally, PVNGS has implemented changes to the Emergency Operating Procedures as corrective actions to address the CEN-152 FRP deviation described in Section I.H. Changes have been made to the FRP to continuously apply the step to check for indications of a steam generator tube leak throughout the Event Control section of the FRP. Continuously applying this step in the Event Control section of the FRP serves the same function at PVNGS as continuously applying the step in the Containment Integrity Safety Function section of CEN-152. As an enhancement, changes were also made to expand the indications used for checking for indications of a steam generator tube leak.

A Steam Generator Tube Rupture Task Force was formed to perform an equipment root cause of failure analysis, evaluate the conditions which led to the tube failure, to develop the response and

recovery efforts, and to ensure that necessary corrective actions were implemented. Corrective actions, primary-to-secondary leakage monitoring, and program enhancements were developed based upon the results of the task force findings and are being tracked to completion under the PVNGS Commitment Action Tracking System. The Steam Generator Tube Rupture Analysis Report contains a detailed description of the task force findings and was submitted by letter 102-02569, dated July 18, 1993, from W. F. Conway to the NRC.

The photo multiplier tube and the scintillation crystal were replaced in RU-141 and the monitor was successfully calibrated. The RU-141 monitor readings in Units 1 and 3 were as expected when compared to the grab sample results. As discussed in Section I.D, previous commitments have been made to the NRC to resolve the moisture problem affecting the operability of RU-141. A design change package for all three units was initiated prior to this event to reroute the condenser air removal system (CARS) condenser vacuum exhaust to the plant vent exhaust eliminating an effluent release path, to convert RU-141 to a CARS in-duct monitor, and to make appropriate hardware and software changes to RU-141. These changes include the removal of the heat tracing. The DCP for RU-141 is being installed to improve the reliability of monitoring the CARS exhaust for increases in radioactivity as a result of primary to secondary leakage via the steam generator.

IV. PREVIOUS SIMILAR EVENTS:

There have been no previous similar events reported pursuant to 10CFR50.73.

V. ADDITIONAL INFORMATION:

Radiological smears were taken to quantify any potential radioactive release which may have occurred through the auxiliary steam relief valve. The results of those surveys were negative.

HPSI flow indication in the Control Room does not indicate full scale such that Control Room personnel have no indication of HPSI flow less than approximately 75 gpm. The simulator does not simulate the square-root-extractor in the flow indicator circuitry and does indicate flow in the 0 to 10 percent range. Operator training was deficient in identifying this difference to Control Room personnel. The PVNGS Incident Investigation evaluated this condition for potential corrective actions. Based on the evaluation, the simulator has been upgraded to exhibit the square-root-extractor function on flow indicators.

In order to determine if any indication of RU-141 failure was present prior to the event, the weekly grab samples obtained from the condenser exhaust during the previous month were reviewed. The activity of the grab samples taken on March 4, 1993, and March 5, 1993, were greater than 5.0 E-6 mu Ci/cc and significantly greater than the corresponding RU-141 readings. This is unusual in that the monitor reading is normally greater than the grab sample results. An investigation was initiated to determine why RU-141 was not declared inoperable based on the discrepancy between the grab sample and the monitor reading. The investigation determined that the appropriate data reviews of the sampling results had not been adequately performed and therefore an opportunity was missed to detect the monitor failure. The individuals involved have been disciplined under the APS Positive Discipline Program.

VI. SPECIAL REPORT:

In Palo Verde Unit 2, there have been 7 total accumulated actuation cycles of the Emergency Core Cooling System to date. This satisfies the requirements of Technical Specification 3.5.2 ACTION b.

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Arizona Public Service Company
PALO VERDE NUCLEAR GENERATING STATION
P.O. BOX 52034 o PHOENIX, ARIZONA 85072-2034

JAMES M. LEVINE 192-00859-JML/TRB/KR
VICE PRESIDENT August 14, 1993
NUCLEAR PRODUCTION

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk

Mail Station P1-37
Washington, D.C. 20555

Dear Sirs:

Subject: Palo Verde Nuclear Generating Station
Unit 2
Docket No. STN 50-529 (License No. NPF-51)
Licensee Event Report 93-001-02
File: 93-020-404

Attached please find Supplement 2 to Licensee Event Report (LER) 93-001 prepared and submitted pursuant to 10CFR50.73. The LER reports a Unit 2 manual reactor trip due to a steam generator tube rupture, and a valid actuation of the Safety Injection Actuation System and the Containment Isolation Actuation System. This supplement is being submitted to provide the equipment root cause of failure analyses and corrective actions. In accordance with 10CFR50.73(d), a copy of this LER is being forwarded to the Regional Administrator, NRC Region V.

If you have any questions, please contact T. R. Bradish, Nuclear Regulatory Affairs Manager, at (602) 393-5421.

Sincerely,

JML/TRB/KR/rv

Attachment

cc: W. F. Conway (all with attachment)
B. H. Faulkenberry
J. A. Sloan
INPO Records Center

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